Docket No. 2016-00222 – Maine Public Utilities Commission Proposed Rule on Customer Net Energy Billing

Comments of Ashley C. Brown

Executive Director of Harvard Electricity Policy Group

Harvard Kennedy School

Harvard University

October 31, 2016

Contents

Background and Qualifications

I am the Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including but not necessarily limited to pricing, market rules, and regulation, as well as environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so this paper represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated. My biography is attached as Appendix A.

Introduction

The State of Maine Public Utilities Commission has issued a Notice of Rulemaking relative to proposed amendments to Maine's Net Energy Billing Rule. The proposed amendments increase the number of systems potentially eligible for Net Energy Billing (NEB), but also provide for the very gradual reduction of the subsidy provided by NEB, bringing NEB closer to reflecting the true costs of service provision to NEB customers by gradually eliminating credits associated with the transmission and distribution (T&D) portions of customer bills, focusing the net energy credit on the energy value actually produced by NEB customers.

The Commission deserves commendation for joining with many other Commissions across the U.S. in taking up reform of a pricing regime that is not only outdated, but imposes unfair burdens on many consumers, particularly those at the low end of the income spectrum, distorts efficient price signals, supports inflated prices for rooftop solar, and is harmful to the long term sustainability of solar energy. Although the proposed reform is more incremental than ideal, it still represents a significant step forward in redressing the adverse effects of Retail Net

Metering (or, following the Maine language, Net Energy Billing)[1]. As I explain below, the proposed revised rate would bring Maine's tariff for distributed generation much closer to fulfilling the classic pricing principle of "cost causer pays" and would make significant strides towards reducing the cross-subsidy from non-solar to solar customers that necessarily results from the current NEB tariff. In what follows I discuss the following topics:

- Traditional utility ratemaking principles and the origins of retail net metering for rooftop solar;
- How retail net metering suffers from problems associated with cross-subsidies, inefficiency, and unfairness to competing resources;
- The problems with "value of solar" claims, and why value of solar analysis generally, and the Maine "Distributed Solar Valuation Study" in particular, do not provide any justification for continuing the burdensome and unfair cross subsidies intrinsic to retail net metering;
- How current efforts nationwide to reform retail net metering, and Maine's proposed Net Energy Billing reform, can help to address current inequities and inefficiencies.

[1] In the discussion that follows, I will use the term "retail net metering" in writing generally about rates that allow rooftop solar customers to receive credit for all per kWh retail charges on their bill (including both energy charges <u>and</u> charges such as transmission and distribution). I will use "Net Energy Billing" when referring specifically to Maine, keeping in mind that the proposed <u>revised</u> Net Energy Billing tariff would no longer qualify as Retail Net Metering, since it would gradually transition to giving credit to customers only for the <u>energy</u> value of their distributed generation production.

Cost-based Utility ratemaking principles

In his seminal 1961 book on utility ratemaking, the economist James Bonbright,[2] whose writings on the subject are widely regarded as authoritative, argued for the importance of a "cost of service" standard in setting rates.[3] Writes Bonbright:

> *[O]ne standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—the standard of cost of service, often qualified by the stipulation that the relevant cost is* necessary *cost or cost reasonably or prudently incurred.*[4]

In implementing "cost of service" ratemaking, ratemaking bodies typically follow a two-step process: 1) determining the utility's total costs—including a fair rate of return on capital investments, and 2) setting rates by allocating a share of those costs to different classes of customers and then selecting rate structures to recover sufficient revenue from each class of customer.

The three most important types of costs for electric utilities are 1) variable energy costs: the total number of kilowatt hours (kWh) used; 2) demand costs: the total capacity (kilowatts, or KW) the utility must build and maintain in order to meet peak demand—generation, transmission, and distribution adequate to supply all the power needed at the moment of the very highest demand (keeping in mind that the obligation to serve is unlimited); and 3) fixed costs: costs that must be incurred regardless of kWh or KW, and which do not vary with demand.

---

[2] Bonbright, who died in 1993, was a long time member of the Business School Faculty at Columbia University and served for some time as Chairman of the New York Power Authority. He is widely regarded as one of the nation's most distinguished writers and commentators on regulations and a most important thought leader on the subject.

[3] This view is generally held by others as well. *See, e.g.*, https://mitei.mit.edu/system/files/Electric_Grid_8_Utility_Regulation.pdf.

[4] Bonbright, op cit, p. 67.

Fixed costs are typically thought of as costs that are unaffected by individual customers' changes in energy consumption. Examples include the costs of customer service and billing.

For residential customers, those three separate kinds of costs have traditionally been bundled together into two-part rates, consisting of a monthly fixed charge[5] and an energy charge (based on total kilowatt hours used). Commercial and industrial (C&I) utility customers, in contrast, have long been subject to three part rates, corresponding with the three types of utility costs. Thus, rates for a commercial or industrial customer typically include a fixed charge and two variable charges—an energy charge, based on total kilowatt hours used, and a demand charge, based on how much capacity the utility needs to maintain to meet the customer's peak demand (measured in kilowatts).[6] Accordingly, C&I customers are not only positioned to reduce both system costs and their own costs by getting a discrete demand price signal, but by providing that signal, new market entrants with the capability of managing demand costs could enter the market and provide such services.

Residential utility rates and Retail Net Metering

The initial connection of rooftop solar systems to the grid posed an issue for utilities and regulators. If customers supply power to the grid, how should they be compensated? When rooftop solar systems were first connected to the grid in the 1980s and 1990s, most households had a single meter capable only of running forwards, backwards, and standing still, and utilities and regulators had limited options. Given the very limited amount of rooftop solar market penetration anticipated at the time, and the high cost of rooftop solar, large scale investment in

[5] Traditionally, the fixed charge on the bill of a residential customer represented only a tiny fraction of the totality of the fixed costs. The bulk of the fixed costs and all of the demand costs were recovered through volumetric based rates (i.e. on a per kwh basis).

[6] It is interesting that when talking about the forces that likely would prompt a utility to adopt a demand charge for industrial customers, Bonbright calls out distorting effects caused by industrial customers who provide some of their own generation. (Bonbright, pp. 309-311)

new technology or overall tariff reform was not a priority.[7] Many utilities adopted retail net metering (or, as it is referred to in Maine, "Net Energy Billing"). Under a retail net metering tariff, a single meter for these customers runs forward when solar PV DG customers are purchasing energy from the grid. When those customers produce energy and consume it on premises, the meter simply stops, and when the customer produces more energy than is consumed on premises, the meter runs backwards as the excess energy is exported to the grid. Thus, the solar PV DG customer pays full retail price for all energy taken off the grid, pays nothing for energy (or such fixed costs as distribution, transmission, generating capacity, or demand costs) when energy is being produced on premises, and is credited the fully delivered retail price (for all energy plus all fixed costs, despite the fact that solar customers incur no such fixed or demand costs) exported into the system. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due or the utility credits the customer for excess energy delivered.

Under Retail Net Metering, therefore, customers produce generation, but are compensated at rates that reflect the full cost of generation and of transmission and distribution. This generous arrangement seemed to make sense originally, at a time when market penetration of rooftop solar was negligible, when rooftop solar systems were far more expensive than they are today, when metering technology was relatively primitive, when wholesale energy and capacity markets did not generate the very sophisticated and unbundled signals they do today, and when the amount of fixed and demand costs that would be bypassed by widespread deployment of rooftop solar were unknown. To the extent that any policy considerations contributed to its adoption, it was that RNM would provide a short-term stimulus to the

[7] Indeed, some utilities, trying to avoid the issue altogether, simply refused to interconnect rooftop solar units to the grid at all.

development of distributed solar technology, not that it was sustainable as a long term pricing methodology.[8]

Today, the technological limitations that were a primary driver of current residential retail rate design have largely disappeared. "Smart meters," as well as internet-based technology, are capable of measuring not only how much electricity consumers use in a month, but when and even how they use it.

At the same time that smart meters have become widely deployed, the costs of solar systems have declined dramatically, with the costs of the solar panels themselves showing particularly dramatic declines. As I argue below, the full benefits of the declining costs are not being passed on fully to customers (solar and non-solar alike)—however, even so, the price of a rooftop solar system is significantly lower than it was when regulators initially settled on generous retail net metering schemes as a way of providing a short term boost to enable rooftop solar to attain full commercial viability. Now that the costs of rooftop solar have declined that rationale for tolerating the flaws of net metering no longer applies. Stated succinctly, the underpinnings of net metering: dumb meters, poor energy price signals in the wholesale market, miniscule market penetration by distributed resources, and out of market costs, are all historical relics that decidedly not characteristic of 21st century electricity markets

What's wrong with retail net metering?

Through RNM, solar customers have until recently had the same residential tariffs applicable to them as were applied to non-solar residential customers (adapted, of course, to give credit for solar production). However, by the standards of cost-based ratemaking, traditional residential tariffs (i.e., volumetric rates based on kWh, and encompassing charges related to

[8] While the full effects of retail net metering were unknown at the time of their adoptions, many jurisdictions, just to be cautious about the unknown, actually hedged against severe distortions by capping the amount of rooftop solar that would be on an RNM tariff.

generation, transmission, and distribution), when applied to customers with solar generation, do a markedly worse job of reflecting actual customer costs than they do when applied to other customers.

This breakdown of the relationship between costs and rates has three main consequences:

- Cross subsidies. Distributed generation customers are undercharged for their usage, and end up subsidized by customers without distributed generation;
- Inefficiency. Distributed generation customers do not receive price signals that would encourage them to maximize the value of the solar energy they produce; at the same time, the distributed solar industry, shielded from market pressures, fails to maximize efficiencies and savings to customers.
- Unfairness to competing technologies.

Cross subsidies

As discussed above, traditional rate plans, including Maine's existing Net Energy Billing plan, use volumetric rates to recover both fixed and demand (transmission and distribution) costs. Customers who generate their own electricity use less electricity, but the fixed costs of service still exist, and the demand costs are largely unabated. The result of linking RNM with a purely volumetric rate structure that makes no distinction between generation costs and distribution and transmission costs is a subsidy to rooftop solar customers. The costs of that subsidy are borne by the rest of the utility's rate base.

This subsidy does not exist for most residential customer classes. This is because most customers' peak demand (measured in KW) and overall kWh usage typically vary together. (This is true for customers who invest in energy efficiency, as well as other customers). For solar DG customers, however, the traditional relationship between peak demand (KW) and overall kWh usage breaks down. Solar customers can reduce their kWh usage by a lot (especially if they get credit for excess kWh produced) while only slightly reducing their peak demand (or even, in some cases, increasing it).

The fact that customers with rooftop solar may produce energy when the sun is shining does nothing to reduce the utility's fixed per-customer costs and, at least in the short run, has not been reliably shown to reduce the capacity costs the utility must incur in order to make sure that it is prepared to meet all of the electric requirements of the solar customers. Thus, when solar DG customers are producing energy and not buying it, the utility cannot fully offset the revenue loss by simply buying or producing less energy. Thus the utility has a revenue shortfall, which must be made up by collecting more money from other customers.

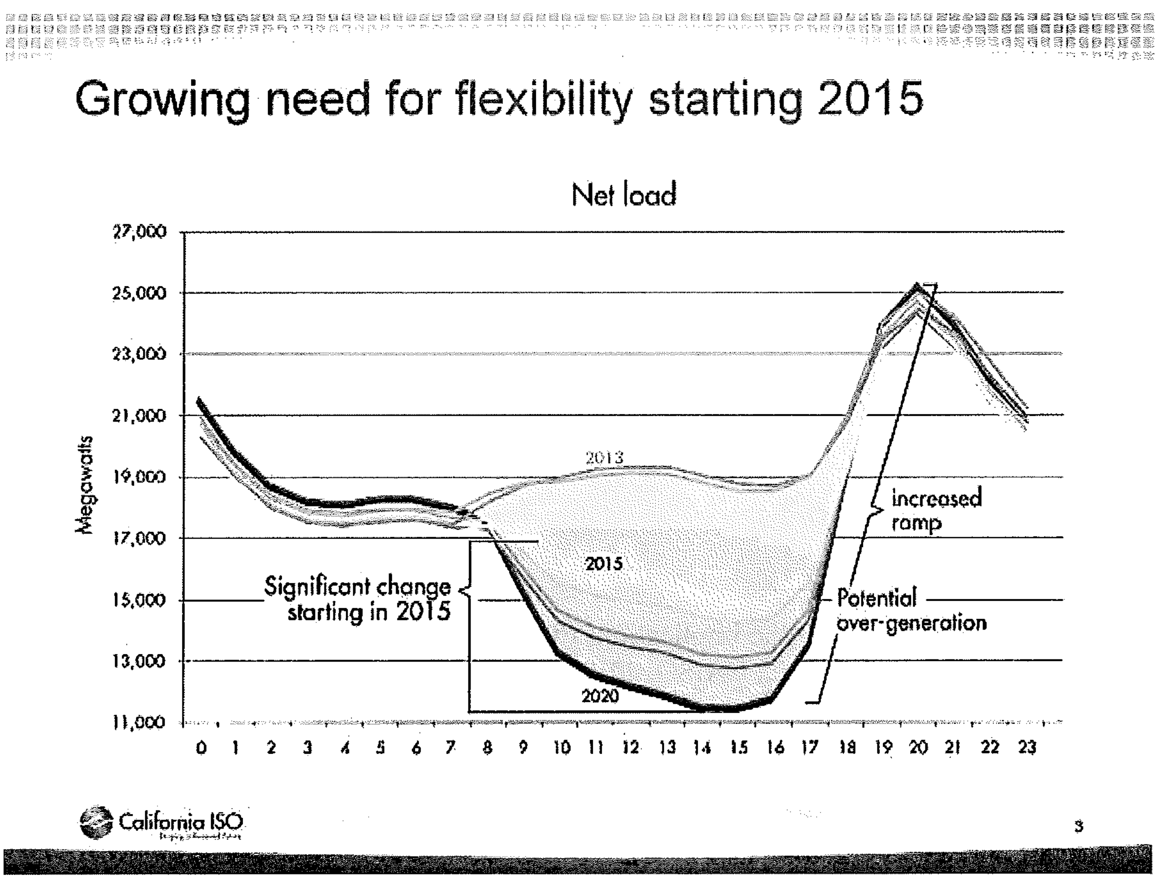
Rooftop solar generation does not significantly offset a utility's capacity costs for two reasons. The first is that solar production is, with some minor exceptions, not coincident with system-wide peak demand.[9] The second reason is that even if solar production generally matched the time when demand was projected to be at its peak, solar production is intermittent, unpredictably so,[10] and thus not dispatchable by the grid operator (i.e., the grid operator cannot call upon it to produce to meet peak demand, or stop producing when there is cheaper, excess capacity on the system). For a utility that is required to meet all of the electricity demand of customers in their service territory, the existence of rooftop solar therefore does little to avoid the

[9] As can be seen below, in the charts from ISONE on "Seasonal variation in load profiles," there is zero overlap between solar production in spring and winter. Summer shows a limited amount of overlap, which diminishes with greater levels of solar penetration. In New England, wholesale electricity prices are higher during the winter, so this means solar is not offsetting peak energy costs during the most expensive time of year. (See ISONE, 2016 Regional Electricity Outlook, p. 23, at https://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf)

[10] It is important to note that rooftop solar is doubly intermittent. It not only depends on the presence of the sun, but also on how much of the energy being produced is being consumed on premises by the solar host. That is in contrast with utility scale solar, which is a single contingency intermittent resource.

need to incur the costs of meeting all demand and, in effect, providing free back up "battery" service to solar customers.

In fact, rooftop solar production generally creates a new and challenging daily variation in the net load that must be served by the utility, a pattern that has come to be known as the "duck curve." Briefly stated, the "duck curve" refers to the phenomenon by which rooftop solar generates large amounts of power in the middle of the day, but as solar production declines throughout the afternoon, the corresponding increase in demand must be met by other generation supplied or procured by the utility.[11] The "duck curve" phenomenon is illustrated in the chart below, in which the belly of the duck shows the increasingly steep drop off and ramp up of net load that is occurring and expected to increase with greater adoption of solar generation:



[11] **http://instituteforenergyresearch.org/solar-energys-duck-curve/;** https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

As is dramatically illustrated in the graph, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in the Golden State has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the drop off in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g. directing solar panels to the west, or linking solar production with storage) is simply something that can no longer be tolerated.[12] While Maine's situation is certainly not identical to California's, it would be pure folly for the state not to learn the lesson of what has gone wrong in other jurisdictions, and adopt a remedy before finding itself in a similar dilemma.

Intermittent sources of generation add additional complexity and cost to maintaining the high degree of reliability expected from the system. This is particularly true because the grid was originally designed to accommodate one-way delivery of electricity, not the two-way exchange associated with rooftop solar generation.[13] Thus, when rooftop solar penetration increases beyond minimal levels, new investments to the grid are required.[14]

---

[12] For further discussion of the implications of the duck curve, see *What the duck curve tells us about managing a green grid*, CAISO, 2013 (http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.)

[13] The two way flow, particularly since the energy inputs to the distribution system are from diverse and unpredictable places, can fundamentally alter grid dynamics by impacting on such critical elements as voltage support and reactive power. Since location of solar units can be a critical element in how these grid phenomena play out, the inability to plan locations for solar dg, almost inevitably drives up utility costs in accommodating distributed solar.

[14] **https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf** at xviii.

Maintaining reliability on a distribution system, particularly where market penetration of rooftop solar has increased significantly, is far more than an engineering challenge. It requires a substantial investment in more modern control and monitoring technology, as well as a substantial rethinking of pricing and the incentives produced from the economic signal produced, in order to move the entire system in directions that will best accommodate all of the changes in the power sector, particularly those related to the increasing deployment of intermittent generating facilities.[15]

In the face of concerns about additional ramping and other system management costs required to respond to the new demand patterns created by the adoption of more solar energy, and of cross-subsidies between customer classes resulting from retail net metering rates, some advocates of retail net metering call for "value of solar" analyses, in order to claim that additional non-energy attributes of distributed solar generation add substantially to the value provided by solar DG to the utility and other customers. As a result, they argue, concerns about cross-subsidies to solar customers are misplaced. These arguments are discussed in more detail below. However, in order to believe that such cross subsidies among customers are cancelled out by the "value of solar", one would need to believe that the "value of solar" supplied is, ascertainably and quantitatively, worth an amount well in excess of the price of energy in the wholesale market at the time the energy is produced, and, in the case of the Maine Value of Solar study, more than double the delivered price of electricity. I discuss in more detail below why this is simply not credible.

[15] The complexities associated with solar dg are further compounded by two additional factors. The first is that the locating of solar units is unplanned, and from a planning perspective, random. That being the case, it is impossible to optimally locate panels to capture system benefits. As long as solar panels are sold or leased on a geographically unplanned basis, there is almost no likelihood that system costs will be systematically reduced by distributed solar. Secondly, distributed solar generation is unseen by ISO New England and is, therefore, not dispatchable. That effectively eliminates the possibility that solar DG makes any contribution to the efficiency of dispatch or of the overall energy market in New England.

The result of the re-allocation of the responsibility for costs is that net metering results in a subsidy from customers without rooftop solar systems to those with solar. These subsidies associated with retail net metering are particularly hard to defend because, in the aggregate, they benefit wealthier customers at the expense of less affluent customers. Less affluent customers lack the means to invest in solar and often do not own their residences, so they are unable to install solar, even if they could afford to do. This gap is exacerbated by the practices of rooftop solar providers like SolarCity, which offer a lease mode for customers without the cash to buy a whole system up front—but the lease product is only available to customers who meet stringent credit requirements.[16]

In addition, as Solar City's internal documents state, RNM encourages rooftop solar providers to "cherrypick" high-income, high-energy usage customers. A 2013 study by E3 Consulting clearly shows the socially regressive impact of net metering. The study found that the median income of rooftop solar customers under RNM was 168% of the median California household income.[17] A similar analysis of rooftop solar customers in California by Severin Borenstein also found installations, despite some decline in social regressivity recently, "heavily skewed towards the wealthy".[18] The Massachusetts DPU only recently made an explicit finding that net metering disadvantaged the poor and gave the state's low income customers explicit relief from having to subsidize solar dg customers in Massachusetts: "…low-income

[16] The idea of lowering credit requirements was raised by SolarCity, but there are no immediate plans for doing so: http://www.reuters.com/article/us-solarcity-fico-idUSKCN0T82ZO20151119.

[17] *California Net Energy Metering Ratepayer Impacts Evaluation.* Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 8, 2013).

[18] Borenstein, Severin. "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives and Rebates." Energy Institute at Haas working Paper. 2015: 26. Paper available online at http://ei.haas.berkeley.edu/research/papers/WP259.pdf.

customers have experienced an increase in bills as a result of the growth of on-site generation."[19]

Inefficiency

RNM encourages inefficient behavior, both on the part of individual customers and the rooftop solar industry as a whole. For individual customers, RNM (especially in conjunction with a flat rate that does not vary with time of day or peak energy demand) fails to provide any incentive to maximize the value (as opposed to the output) of their rooftop solar systems. RNM customers with distributed solar are motivated to produce as many kWh as possible, but not necessarily to target production or manage demand to offset peak consumption.

One example of this problem has to do with the orientation of rooftop solar panels. The monetary value of energy provided to the grid by rooftop solar panels varies depending on the time of day. Generally speaking, energy provided at the time of peak usage is the most valuable. That is because the generating fleet is dispatched on the basis that the least expensive plants are generally dispatched first. As demand increases, more and more expensive plants are dispatched until all demand is met.[20] However, RNM (in conjunction with flat, time-invariant rates, which are common in Maine) provides one signal to customers with solar DG systems—the more you produce, the more you are paid, regardless of the energy market prices at the time of production.[21] For this reason, as a *New York Times* article explains, flat RNM pricing has

[19] See Order 9-30-16 of the DPU, case # 15-155, p. 470: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-155%2f15155_Order_93016.pdf.

[20] It is worth noting that, in general, the economic order to dispatch power plants also has a salutary environmental effect. That is because, in general, the least expensive plants are either non-emitting of pollutants (e.g. renewables), or low emitting, more efficient plants.

[21] Energy prices in the electricity market, as one might expect when supply and demand have to be instantaneously matched, vary widely over the course of every day. Thus the time at which energy is produced is a critical determinant of the price suppliers are paid. RNM ignores

contributed to solar panels generally being installed facing south, to generate the largest total quantity of solar energy over the course of the day (and the greatest savings and/or revenue for homeowners under RNM). If solar rates instead reflected the cost to the grid of the customer's period of highest demand, these panels would be adjusted to capture the most sun during peak hours—for many customers, this would mean aligning panels to face west, generating less total energy, but capturing the late afternoon power of the setting sun.[22] Thus, a customer who works outside the home and uses air conditioning in the evening during the hot summer months might well offset many (if not all) of his or her kWh of usage through robust rooftop generation—but still might impose a significant peak demand load on the grid when he or she arrives home at 6 or 7pm, when solar production is at or near zero, by turning on air conditioning and other electric appliances. In fact, the savings from solar electricity might even encourage such a user to use more peak electricity than he or she otherwise would—keeping the house a little cooler, or otherwise being more free with his or her energy use. Indeed, major solar installation company Solar City's own marketing materials, taking advantage of the lack of explicit and transparent demand cost price signals, promote this type of expensive, highly inefficient use of energy.[23] Thus, RNM incentivizes production in ways that are optimized for the dg solar industry and its customers, not to the system and non-solar customers.

Similarly, RNM discourages the adoption of batteries or other forms of storage in conjunction with rooftop solar production. This is because, under an RNM tariff, the utility operates essentially as a giant free battery available for use by DG solar customers—any excess

---

that market place reality and, under RNM, fetches an above market price for solar dg output that is exported onto the grid.

[22] Matthew L. Wald. "How Grid Efficiency Went South" *New York Times*. October 7, 2014.

[23] A SolarCity advertisement encourages just this behavior: "Go ahead," it reads. "Sleep with the lights on. Solar energy is limitless." **https://mobile.twitter.com/solarcity/status/731167148882690048.** This advertisement is particularly irresponsible because solar power is not generated at night.

energy they produce is credited back to them at the full retail price, and they can use this credit to import an equivalent amount of energy back from the grid at any time at the full retail price. While at first blush that might seem reasonable, it is not sustainable. Solar production is largely off peak, while substantial imports are required at peak by solar customers. The following three charts show the relationship in New England during different seasons of the year, at a range of different levels of solar penetration. They are copied from the ISO New England's webpage titled "Solar Power in New England: Locations and Impact,"[24] and illustrate that facile assumptions made that solar benefits include near-term reductions in peak generation are precisely that.[25]

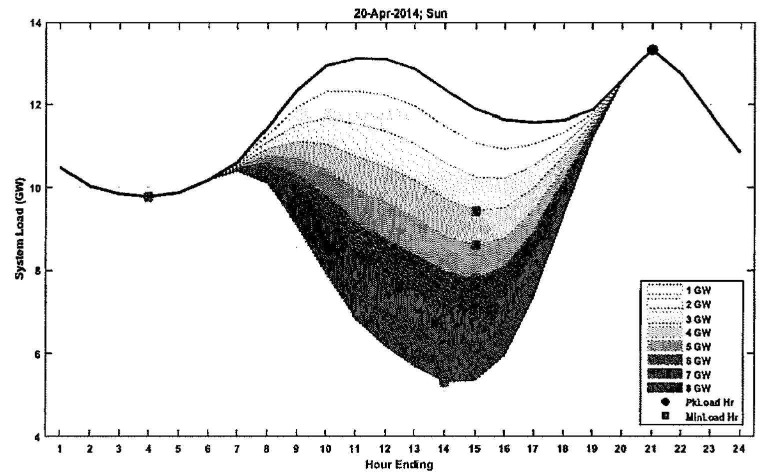
---

[24] Page can be found online at https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

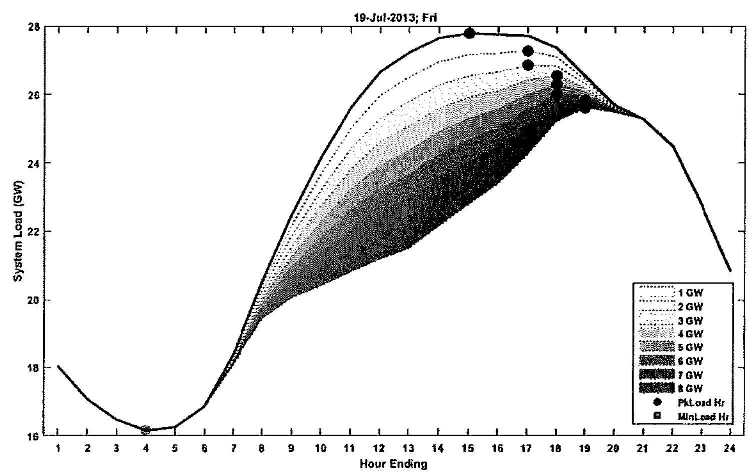
[25] Black, John. "Update on Solar PV and Other DG in New England." ISO New England (June 2013).

Seasonal variation in load profiles, ISONE

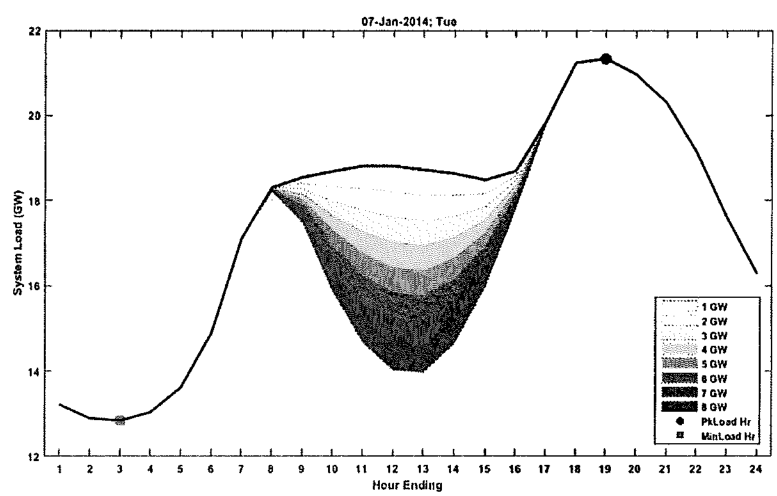
Spring



Summer



Winter



These two charts dramatically demonstrate that on the days chosen as representative of summer, winter, and spring in New England, solar PV peak and peak demand are not the same. Solar PV is completely absent during the winter peak and spring peak (however, it is interesting to note that winter solar production suggests the possibility of New England developing its own "duck curve.") During the summer, there is an overlap between solar production and peak demand, but as can be seen on the chart, and as ISO New England explains in the accompanying text, "Because greater amounts of PV will actually shift the timing of peak demand for grid electricity to later in the afternoon or evening, PV's ability to reduce peak demand will actually diminish over time." It should also be noted that on the days chosen, the sun was shining. The graph, of course, would look very different on cloudy days when solar production is virtually nil.

Technologies currently exist that could help customers with solar pv to manage their production and consumption so as to maximize the overlap between solar pv production and peak demand hours. Possible efficiency enhancers could include simply pointing pv panels to the west, rather than the south, but also using batteries to store off-peak energy, or smart thermostats to optimize energy usage patterns. However, under a flat RNM tariff, DG customers, who would seem to be a natural customer base for energy efficiency and/or capacity savings devices or storage batteries available on the market to better align their energy and capacity demand with system costs, have no incentives to invest in such products, therefore delaying the development of the integrated solar/battery home systems that may be a logical next step for distributed generation. That may be why, for example, Tesla—Solar City's own sister company, run by SolarCity's Chairman Elon Musk, which recently acquired Solar City—reportedly opposes

RNM.[26] As this conflict makes clear, RNM removes an incentive for residential customers to deploy batteries and other forms of energy storage.

A second issue of efficiency relates to the incentives that are or are not provided to the rooftop solar industry itself to maximize customer savings. It appears that the solar installation market is currently such that generous subsidies provided through programs like RNM do not get fully translated into reduced customer costs. The recent MIT study, *The Future of Solar Energy,* observes a "striking differential" between MIT's estimate of the cost of installing residential PV systems (even allowing for a profit margin) and the reported average prices for residential PV systems—actual prices for residential systems were approximately 150% of MIT's cost estimate—a difference between cost and price the MIT researchers did not observe for utility-scale installations.[27] Indeed, as documented in the MIT study, there is evidence now that the declining costs of solar panels, which have been quite dramatic in recent years, are not being passed through to consumers, enabling most of the benefits of declining panel costs to be retained by solar vendors, to the detriment of all consumers, solar and non-solar alike.

A recent study by Lawrence Berkeley National Labs found that out of four countries it compared to the U.S. (Germany, Japan, France, and Australia), the U.S. had the highest prices (per watt of capacity) for installed residential PV systems.[28] The reasons for these high U.S. prices are not fully understood—it is something more than market size, since the U.S. market is smaller than the solar pv market in some of the four other countries studied, but larger than others. A 2014 study aimed at better understanding variations in solar pv pricing, involving collaboration between researchers from Yale, Lawrence Berkeley National Laboratory, the

---

[26] "Net Metering vs. Storage Creates Clash Between Some Allies." http://www.eenews.net/stories/1060025111

[27] MIT, *The Future of Solar*, p. 86.

[28] Barbose, Galen and Naim Darghouth. *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States.* Lawrence Berkeley National Laboratory (August 2016):22-23.

University of Wisconsin at Madison, and the University of Texas at Austin, found a revealing association:

> "...regions with a higher consumer value of solar, considering retail electricity prices, solar insolation levels, and incentives, tend to face higher prices. This phenomenon may be the result of a shift in consumer demand caused by the presence of rich incentives, enabling entry by higher-cost installers and allowing for higher-cost systems. Alternatively, the results may be a symptom of high information search costs or otherwise imperfect competitions, whereby installers in these markets are able to "value price" their systems, effectively retaining some portion of the incentive offered...In the short-run at least, policies that stimulate demand for PV may have the exact opposite of their intended effect, by causing prices to go up rather than down."[29]

That is, RNM, by effectively shielding rooftop solar suppliers, from both robust competition and from cost-based regulation, may be removing a key incentive for rooftop solar installation companies to pass on declining costs to customers.[30]

In fact, emphasizing this very point, in a recent 10K filing, SolarCity, the nation's largest solar dg company, clearly describes this as its business model:

> We compete mainly with the retail electricity rate charged by the utilities in the markets we serve, and our strategy is to price the energy and/or services we provide and payments under MyPower below that rate. As a result, the price our customers pay varies depending on the state where the customer is located and the local utility. The price we charge also depends on customer price sensitivity, the need to offer a compelling financial benefit and the price other solar energy companies charge in the region. Our commercial rates in a given region are also typically lower than our residential rates in that region because utilities' commercial retail rates are generally lower than their residential retail rates.[31]

---

[29] Gillingham, Kenneth, Hao Deng, Ryan Wiser, Naim Darghouth, Gregory Nemet, Galen Barbose, Varun Rai, and C.G. Dong. *Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy*. (December 2014): 20-21. Available online at: http://www.seia.org/sites/default/files/LBNL_PV_Pricing_Final_Dec%202014.pdf

[30] The failure to pass on declining input costs to customers is pricing behavior often considered to be characteristic of monopoly pricing.

[31] SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, p. 38 (available at http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf)

From Solar City's perspective, of course, the issue is not whether rooftop solar can be competitive, but whether it can remain so without suppliers like Solar City having to pass on to consumers some of the cost reductions in their supply chain, something that might reduce their profit on a per transaction basis, but make solar more attractive to more customers enabling more sales. In short, Solar City's, the leading solar dg provider in the country, has a business model premised on keeping prices high in a declining cost industry, and relying on subsidies and cross-subsidies in lieu of the classic economic formulation that lower prices (in this case enabled from lower costs) stimulate demand. Stated succinctly, the business model articulated by Solar City in its 10K filing, and shared by those solar dg vendors who demand retail net metering is to chase subsidies and cross-subsidies rather than to compete in the marketplace.

Unfairness to competing technologies

The failure to provide incentives to invest in efficiency-enhancing technologies points to another problem with retail net metering, which is that retail net metering distorts the competitive market for other resources. In seeking cost-effective means of reducing their electricity bills and environmental impact, consumers have a variety of options. Rooftop solar is one possibility, but there are a variety of competing alternatives; many of them provide greater value to the grid, and, absent rooftop solar subsidies, to the customer himself/herself, most notably various energy efficiency programs and means of flattening out their load profile.[32] The subsidies associated with RNM, however, substantially bias decisions in favor of rooftop solar over these other options, which would be more efficient, and, in the absence of subsidies, would be the most economic for the customer.

[32] Load profile is the configuration of how much energy a customer consumes (kilowatts hour, (kWh)) and precisely when it is consumed. The time when the demand hits its maximum defines the amount of capacity (kilowatt (KW)) a utility must have available to serve that customer.

Rooftop solar is the most expensive form of commonly deployed renewable generation in the U.S. today. The latest annual update of Lazard's *Levelized Cost of Energy Analysis* continues to show this, with a levelized cost for rooftop solar ranging from $184-$300 per MWh, higher than all other energy sources analyzed, including fuel cell, solar thermal, utility-scale solar, geothermal, biomass, wind, and energy efficiency.[33] The Lazard analysis goes on to compare the cost of carbon abatement per ton for different alternative energy resources. As one would expect based on its levelized cost, rooftop solar power had the highest cost per ton of carbon emissions avoided ($335 per ton, assuming gas is the comparison generation). In contrast, Lazard's calculations found that utility-scale solar PV could abate the same ton of carbon emissions at a cost of only $15 per ton. The difference here is staggering. [34]

A recent study by the Brattle Group comparing generation costs of utility-scale and residential-scale PV in Colorado confirms that most of the environmental and social benefits provided by PV systems can be achieved at a much lower cost at utility-scale than at residential-scale."[35] RNM, however, operates to make rooftop solar more attractive than other forms of renewable generation via subsidies from non-solar ratepayers, diverting resources away from competing (and, arguably, superior, technologies).

---

[33] *Lazard's Levelized Cost of Energy Analysis-Version 9.0.* November 2015. Data cited is from p. 2 table, "Unsubsidized Levelized Cost of Energy Comparison." Full report available online at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

[34] *Lazard's Levelized Cost of Energy Analysis-Version 9.0.* November 2015. Data cited is from p. 6 table, "Cost of Carbon Abatement Comparison." Full report available online at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

[35] Bruce Tsuchida, Sanem Sergici, Bob Mudge, Will Gorman, Peter Fox-Penner, and Jens Schoene, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area." The Brattle Group, July 2015, p. 3.

Value of Solar Claims: Does additional "value" provided by rooftop solar change the calculus in establishing rates for distributed generation/partial requirements customer?

In the face of arguments like those above against retail net metering, advocates of RNM have tried to develop theories as to why the obvious cross-subsidization does not occur in RNM. Their line of line of argument is based what has been described as "value of solar" theory, and it is particularly salient in Maine, where a recent study found distributed generation to have an astonishing (unbelievable, in fact) levelized value of 33.7 cents per kWh (in a state in which a typical residential customer rate might be around 13 cents per kWh). As I argue below, "value of solar" numbers, in general, should be treated with extreme caution. Value of solar calculations, far from being definitive, are part of an ongoing debate, in which there is no consensus. In the case of Maine specifically, as I will go on to explain in more detail, there are a number of significant problems with the analysis presented in the *Value of Distributed Generation* report that result in grossly inflated claims of "value" provided by distributed solar energy.

Problems with the "Value of Solar" from PURPA to today

Generally speaking, studies of the "VOS" are highly subjective and readily manipulated, because there is no established, commonly accepted methodology for assessing the value of solar, and, furthermore, given the complexity of the analyses needed to assess all the various "VOS" claims, no analysis can effectively avoid the need to make multiple subjective judgments. Indeed, the "calculation" requires so many inputs, assumptions, estimates, etc., all of which are highly contestable, that no consensus may be possible.

Value of Solar pricing is an attempt to quantify the costs a utility avoids because of the deployment of rooftop solar generation. So-called "avoided cost" pricing has a history in utility regulation, and it is not one that inspires any confidence in its use. In 1978, Congress enacted

PURPA (the Public Utilities Regulatory Practices Act). Among other things, PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from "qualifying facilities" (QFs) at their incremental or avoided costs. "Avoided costs" was defined as: "[T]he incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."[36]

Efforts to calculate "avoided costs" rapidly encountered difficulties. As one article describing avoided cost pricing under PURPA observed:

> Errors in the estimation of long-run avoided costs are inevitable. However, as PURPA was implemented by state regulators in the 1980s, a combination of questionable methods of setting avoided cost and/or poor application of these methods led to excessive avoided cost payments and forced utilities to buy QF capacity even when the utilities did not require more capacity. In addition, excessive, non-dispatchable QF output created operating problems for some utilities. Many complaints about PURPA's implementation were raised by electric utilities and others.[37]

As was clearly demonstrated by the PURPA experience, avoided cost analysis is subject to the biases and policy predispositions of the authors and/or sponsors of such studies.

This reality is well illustrated by the extraordinarily wide variance in the conclusions of VOS studies. The range is dramatic, with a VOS study in Louisiana finding a negative value (principally because it considered the cost of other government subsidies already supporting solar, which are usually excluded from such discussions), with Maine's own VOS having the distinction of being an extreme outlier on the high value side, with a calculated "value" in Maine

[36] 18 CRF §292.101(b)(ii)(6) (Public Utility Regulatory Policies Act of 1978).

[37] Graves, Frank, Philip Hanser, Greg Basheda. "PURPA: Making the Sequel Better than the Original." Prepared for the Edison Electric Institute (December 2006). Available online at http://www.eei.org/issuesandpolicy/stateregulation/Documents/purpa.pdf

of 33.7 cents/kWh.[38,39,40] Additional disagreement exists over the individual components that make up VOS analysis.

Furthermore, analyzing the "value" of rooftop solar in isolation produces an essentially meaningless number, in the absence of similar "value" analysis for all other competing resources. VOS studies are technology-specific (almost always limited to rooftop solar) and almost always ignore market conditions and how the calculated value of rooftop solar compares with the value of competing resources to meet the same objectives.

In addition, VOS studies rarely, if ever, look at the opportunity costs associated with spending money on rooftop solar, as opposed to using that money on something that produces energy and/or reduce emissions more efficiently (many other major renewable technologies, as discussed above, beat rooftop solar by these measures). This kind of one-dimensional, out-of-context analysis of an extraordinarily complex subject is almost useless as an evaluative tool, much less a rationale to justify administrative extractions of higher rents from consumers.

Even a cursory analysis of the various individual elements generally offered up to calculate the value of solar suggests that, with the exception of avoided short-term energy costs, and perhaps, on a time and location specific basis, some savings on transmission congestion,

---

[38] Dismukes, David E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. Prepared on behalf of the Louisiana Public Service Commission.* Prepared on Behalf of Louisiana Public Service Commission Draft, February 27, 2015. *Please see:* **http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5.**

[39] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* **http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.**

[40] To put the 33.7 cents /kWh valuation in perspective, that number is more than double the full retail rate of Maine's largest electric utility. In other words, the authors of that study calculated that the "value" of the energy produced by each rooftop solar installation is worth double the full delivered cost of electricity. That is the equivalent of saying that the value of a part of a product is worth double the value of the entire product.

there is little bankable value there. Few of the "values" attributed to rooftop solar in Maine's or other VOS studies stand up to scrutiny, and those that do are compensated under appropriate ratemaking, to the extent they are real[41].

Avoided energy costs

Rooftop solar generation, when produced, does reduce the amount of electricity the utility must provide. Almost every participant in the conversation about the "value" of solar agrees on this.[42] Caution should be exercised, however, when the suggestion is made that the value of the generation to be offset should be calculated on a "levelized" basis—projected for twenty years, and then averaged. This introduces unnecessary and unhelpful speculation about future gas prices and inflation, while doing little to illuminate how actual current cost savings should be considered. A "levelized" value number looks bigger, but caution must be used in understanding what this number means—comparing a larger "levelized" value of solar against current (non-levelized) costs of RNM, for example, is comparing apples and oranges.

---

[41] An example of appropriate ratemaking compensating rooftop solar for benefits would be to apply the relevant locational marginal price (LMP) to the price paid for rooftop solar exported to the grid. That automatically captures not only the precise avoided energy cost at the same time that the energy is produced, but also captures the transmission congestion benefit (or cost, depending on the circumstances at a given location at a given time).

[42] Many value of solar analyses present the avoided energy cost as a "levelized" number, which factors in predictions of increasing energy costs in upcoming years to come up with a "levelized" avoided energy cost which is higher than the actual energy cost today. It is tempting here to focus on the fallibility of making reliable predictions about future energy costs (look at recent trends in natural gas prices. Most people did not foresee recent declines). But the whole issue of prediction is a red herring in this context, because RNM does not provide utilities with ownership of distributed solar resources, and therefore gives it no protection against future energy price increases. If an RNM system of compensation continues, reimbursement rates will always be tied to overall energy price increases. So costs of RNM to the utility will go up right along with savings. Trying to give solar resources credit ahead of time for rising energy costs needlessly complicates the analysis, which would then have to be balanced with appropriately rising net energy metering costs. It is simpler and less misleading to use current avoided energy costs, recognizing that these need to be updated regularly.

Avoided capacity costs (generation and transmission)[43]

The idea that having a lot of distributed solar on the system means that the utility requires less capacity of various kinds is one of the commonly asserted claims made by retail net metering advocates. These claims are unfounded. Solar energy is intermittent and only available when the sun is shining, and, in the case of rooftop solar, only available for export to the grid if the sun is shining and the solar customer is not using the energy produced on his/her rooftop. It is not and cannot be relied upon to produce any energy when called upon to do so, nor to reduce demand reliably, because there is no way to be certain that the conditions necessary for rooftop solar energy to produce when asked to do so will be met.

Of course, in their planning, utilities do consider the potential impacts of rooftop solar generation on overall capacity needs, from a probabilistic point of view. However, as a former regulator, I believe there is an important distinction to be made in thinking about capacity from a ratemaking standpoint, as opposed to a planning standpoint. From a ratemaking standpoint, payments for capacity should depend on performance.

In the wholesale market in which, when a generator obtains a capacity payment, the generator agrees to either deliver the energy when called upon to do so, or assumes liability for supplying replacement energy. In contrast, rooftop solar providers under RNM make no such assurances. If the utility incorporates this "value" into rates, it potentially pays twice—first, in a lower rate for rooftop solar customers, and, second, if the rooftop solar producer fails to deliver, the utility must pay again, this time to an alternative supplier to provide what the solar provider did not. It is, quite simply, a "heads I win, tails you lose" proposition. From a consumer

---

[43] Capacity in electricity refers to the generating resources to deliver energy when called upon to do so. What is produced, of course, is energy, whereas capacity is the ability to produce when called upon to do so.

perspective, the capacity value claimed by VOS proponents is for phantom capacity, not something real.

Potential savings related to power flow: Line loss reductions and ancillary services

It is true that energy losses occur during transmission and distribution. However, whether or not solar PV systems reduce the amount of energy lost in long distance transmission and distribution is a fact-specific question, dependent on an array of variables (including the location and times of generating energy of rooftop solar systems), and the answers may be counterintuitive. Electricity flows on wires according to laws of physics, following the course of least impedance, a natural phenomenon impacting every interconnected wire, regardless of whether the wire is sized to withstand the current.[44] As a result, energy flow on the grid is highly dynamic in real time. Every injection or withdrawal of energy impacts the ability to access the grid throughout the system. Maintaining optimal grid functionality requires careful planning, vigilant and prudent dispatchers, and the ability to call upon resources to provide what are called ancillary services, such as voltage support, reactive power, black start, and other very location specific service that are essential to grid operations, many of which also affect line losses.

Thus, with respect to the distribution grid, the production or non-production of energy affects line losses on a very location- and time-specific basis. While it is true that DG <u>can</u> have a salutary effect on line losses, it is equally correct to say that it could have an adverse effect of line losses. As a matter of physics, there is simply no generic "value" associated with rooftop solar reducing line losses on the distribution grid. Indeed, as noted above, given the random,

---

[44] The flows of the high voltage transmission system and the low voltage distribution system are separate and distinct from one another, so the flows according to least impedance are system specific. While demand shifts at any given interconnection point where high voltage is stepped down to low voltage can influence flows on the high voltage system, the actual flows between the two systems are separated by transformers, so the flows between systems are controlled.

uplanned siting of solar dg units, the likelihood that solar panels will be optimally located and in appropriate configurations to add system value is almost non-existent. VOS claims of such value are little more than claiming that solar producers are entitled to compensation for system benfits that, perhaps, in theory they could provide, even though they simply cannot be rfelied upon to deliver.

With respect to the transmission grid, the issue is a bit different, because rooftop solar is not directly interconnected to the high voltage system. Nonetheless, rooftop solar, simply as a matter of scale, probably has very little impact on transmission line losses. Further, (here the counterintuitive interconnected properties of electricity grids come into play) there is no simple and reliable relationship whereby less power delivered to a certain location guarantees less congestion on the grid, and correspondingly fewer transmission losses. Electricity on an interconnected grid impacts the whole grid according to Kirchoff's law. Inputs into the grid need to be carefully balanced with withdrawals to avoid overloading any specific wire and to allow for access to the cheapest possible generation. The impact of lessening demand from a particular node on the grid depends on the specific constraints affecting dispatch at a given point in time. Just as in the case of distribution, to the extent that rooftop solar impacts transmission line losses at all, it is very location and time specific, so generic conclusions are simply not reliable.[45]

If utilities got to select exactly where distributed generation was installed, it might be possible to leverage DERs to provide more reliable transmission and distribution benefits. But this not currently how distributed generation installations work.

For this reason, there is no basis to claim that solar PV systems, *ipso facto*, reduce losses. Furthermore, additional costs can also be the result of efforts to incorporate new DERs. On

[45] For a technical discussion, see M. Rivier, "Electricity Transmission," in Perez-Arriaga, ed. *Regulation of the Power Sector* (p. 276, footnote 8), which acknowledges that in some cases, increased demand at a node (a distribution node) can decrease system costs overall.

distribution systems, this point is being debated among experts, and it appears to be that DERs could well, in some circumstances, increase losses or cause additional costs to be incurred to cope with the newly bi-directional energy flow on the distribution grid, which was designed and built to accommodate one directional flows. With regard to transmission losses, it is certainly true that distributed solar PV does not rely on high voltage transmission. That, however, is no assurance of value. Rooftop solar can also adversely impact the transmission system because of its intermittent and unpredictable nature, which requires utilities to incur expenses to assure that backup power is available in order to be able to instantaneously call upon other resources. Similarly, even when solar units are producing energy, those flows have the potential to cause changes in the flows on the high voltage transmission in ways that add congestion to the system. Should either such circumstance occur, it is likely that losses would be increased, not decreased.

Ancillary services, similarly, can be impacted in both positive and negative ways by distributed solar generation. Certainly, there is the potential for distributed solar installations to include "smart inverters," which have the potential to provide frequency regulation and reactive power even when the sun is not shining—but these are potential capabilities, which RNM does nothing to incentivize, and which should be thought of as a separate product from rooftop solar. To realize the potential benefit here, some form of separate compensation would be needed—and, in my opinion, such compensation should, like compensation for other forms of ancillary services, be provided as a result of services actually provided, not in the hope of services that could potentially be provided at some future date.

Environmental benefits (emission mitigation costs)

Even the emissions mitigation benefits associated with rooftop solar are not unquestionable. As discussed above, rooftop solar may have no emissions when producing energy[46]—but this is only a benefit if it is displacing fossil fuel generation of electricity, not competing non-carbon resources such as utility-scale solar or wind. It is simply impossible to show that rooftop solar always displaces carbon emitting units. The issue is made even more complex by the fact that even when it is carbon emitting plants that are being displaced, the displaced plants are forced to ramp up and down in response to the intermittent flow of the solar produced energy because of the "duck curve," as discussed above. Such ramping, in most fossil plants, run contrary to the design parameters of the plant, therefore causing it to operate on a considerably less efficient basis, a circumstance which is very likely lead to more emissions, not less. It is also true that in New England, off-peak energy such as rooftop solar will not displace high emitting plants, such as coal[47] or oil[48], whose operating characteristics are such that they are extremely unlikely to be displaced by rooftop solar. What is likely to be displaced are natural gas units, which are low level emitters. Hence using solar to offset natural gas is an economically inefficient way to reduce carbon. In fact, given that we have a regional cap on carbon under the Regional Greenhouse Gas Emissions program (RGGI), any carbon reduction through net metering, a mechanism outside of the RGGI cap, serves to drive down the price of carbon in the marketplace, thereby making carbon reduction less efficient, more expensive, and suppressing the development of more efficient technologies to reduce carbon emissions. Simply stated, it is counterfactual to assume, as a linear proposition, that more rooftop solar means fewer emissions.

Avoided purchased power/risk ("hedging")

[46] If one considers the entire cycle of manufacturing solar panels, most of which are made in the world's most carbon intense economy, China, plus the necessity of shipping the panels halfway around the world, it can hardly be argued that solar PV is carbon neutral.

[47] It is worth noting in this context that New England has very few coal burning plants and those that remain are slated for retirement fairly soon. Moreover, those that are operating are baseload units which are not designed to ramp up or down depending on the state of solar production

[48] To the extent that oil fired plants are still utilized in New England, they are generally peaking units. Given that solar production in the region is almost entirely off peak, oil plants are not displaced by solar dg.

Many "value of solar" advocates suggest that distributed solar power should get credit, when evaluating net energy metering, as a hedge against increasing natural gas costs. This does not make sense in the context of discussions of retail net metering and the value distributed solar offers to the system as a whole. Solar power potentially has value as a hedge against natural gas, but only for the owner of the solar panels. For a utility that will be buying power from solar panel owners without a long term fixed price contract (as is the case under RNM) the hedge value under net metering is essentially nonexistent. The reason is that the price to be paid by the utility for power from rooftop solar will include all of the elements included in the monthly electric utility bill, including the full cost of energy. When gas is expensive, this price paid by non-solar customers will be higher; when it is cheaper, it will be lower. So, if it is worth hedging against variations in the price of natural gas, the utility should buy the same hedge against variations in the price of rooftop solar power. From the utility's and the non-solar customer's point of view, the two costs will vary together. Thus, the hedge value is not only zero, any consideration paid for such a hedge would be more expensive than incurring the risk from which protection is sought—this is like paying for vacation insurance that costs more than the trip itself.

- *Avoided distribution grid costs*

While it is theoretically possible that there could be benefits for the low voltage grid as a result of distributed solar generation, it is also possible that there will be more cost than benefits. Distributed generation imposes costs and burdens on the grid by adding transaction costs and, in many cases, by compelling substantial changes in local networks to reflect the fact that the flow of energy is being changed from one directional to bidirectional. Significant geographic concentration of solar PV may cause the utility to have to make very substantial capital investment to upgrade the grid to accommodate the new flows put on the system. In California, in fact, serious consideration is being given to totally restructuring distribution grids in order to effectively manage the new flows, both physical and financial.[49] While such accommodations can be made, policy makers do need to understand that there are costs associated with making them and should be mindful of who must bear responsibility for those costs.

Part of the problem is that, unlike all of other energy resources whose siting is part of a carefully planned integrated process, in which the connecting infrastructure is often dealt with concurrently, or is capable of anticipation, distributed generation is completely unplanned. In fact, since the installation of rooftop solar is the result of an individual's decision, there is no possibility to plan The result is that the operator of the low voltage grid has to constantly play "catch up," a process which can be time consuming and costly. Moreover, even in cases where a rooftop facility does reduce distribution costs, that is a specific function of location and time, something which may not be true of a neighbor's facility, much less one located across town. Thus, any generic claim that the installation of rooftop solar adds value to the grid simply cannot be regarded as credible.

Avoided water use

Avoided water use is in some cases cited as an additional "value" provided by rooftop solar. However, the cost of water is included in the cost of producing energy—so there should not be a need to count "avoided water use" as a separate value. In other words, if rooftop solar offsets the need to energy produced where water is used in the production process, that water is being saved and is, therefore, internalized into the cost of energy. Considering water in value calculations essentially double counts avoided water use.

[49] Southern California Edison recently put forward a rate case which included $2.3 billion for changes to the grid to accommodate distributed energy resources. See September 21, 2016 Utility Dive article: http://www.utilitydive.com/news/how-southern-california-edisons-new-rate-case-would-transform-the-grid/426493/

The Maine "Distributed Solar Valuation Study"

In the context of any discussion of Net Energy Billing in Maine, the 2015 *Maine Distributed Solar Valuation Study* should be addressed. The study itself has garnered considerable attention as an outlier in identifying an extremely high "value" of distributed solar in Maine, finding an astonishing "levelized" value of 33.7 cents per kWh over the 25 years analyzed.[50] While the study has the merit of being transparent about its methodology, a close examination of the methodology itself reveals that not only does it suffer from the general problems discussed above, but also from some very serious methodological flaws that discredit its findings of a high value of solar for Maine. Below, I examine some of the key value categories and explain what is wrong with the methodology and findings of the study in these areas.

Avoided Environmental Costs

For this category of avoided costs, the Maine study estimates a much higher value than is found many other studies (a levelized value of 9.6 cents per kWh). Closer examination of the methodology here is revealing. The Maine study gets a significant amount of this value from the calculation of avoided costs related to sulfur dioxide (SO2) and nitrous oxide emissions (NOx), which can have significant and costly health impacts. The Maine study is not the only one that includes costs related to SO2 and NOx emissions, but, compared to other studies, it finds a much greater effect—a surprisingly large effect, assuming rooftop solar generally replaces natural gas generation, since natural gas generation has very low emissions of these pollutants. The big culprit in SO2 and NOx emissions is coal-fired generation, not natural gas generation.

So is the marginal resource in Maine that is being displaced coal generation? Analysis elsewhere in the Maine study would suggest not—avoided energy cost calculations are tied to natural gas futures and price forecasts. However, if you read the appendix (as I mentioned above, to its

[50] *See* Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* **http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.**

credit, the Maine report clearly documents its questionable analytical choices—though the reader must be diligent to find the necessary information), the authors note that the AVERT data used to calculate emissions "includes New York, which is not part of the ISO-NE control area."[51] The appendix goes on to clarify that if the authors had in fact limited the analysis to "FTA rates"—emissions rates for units fueled with oil and natural gas (closer to what the Maine study authors assume is being displaced in their marginal cost analysis) emissions rates would have been radically lower. In fact, the appendix goes on to acknowledge that, "If the FTA rates were used rather than the AVERT results assumed for this study, the displaced emissions and the net social costs calculated below would be reduced to 8% and 20% of the values calculated here for SO2 and NOx, respectively."[52]

What this boils down to, is an admission that the "value" attributed to SO2 and NOx emission reduction is a complete fiction, based on a calculation that rooftop solar in Maine would somehow reduce coal plant emissions in New York. This is ridiculous. Coal, as noted above, is at all times unlikely to be used as a marginal resource—and these coal plants are not even part of the same dispatch system as Maine! The use of this number as if it means something in the main body of the report is unjustifiable. The tone of the report suggests a sober, earnest, scholarly analytical effort—but this shameless distortion makes one wonder if what is really going on is an attempt to use analytical tricks to inflate the VOS in whatever way is possible.[53]

Taking this egregious problem together with other issues, Maine study's 33.7 cent "levelized value" is extremely doubtful. The avoided environmental cost estimate in the Maine study just discussed adds up to 9.6 cents of the "levelized" 33.7 cent/kWh value—a significant percentage of the value that is found.[54] Another 10.3 cents of "value" are attributed to categories which, as I

[51] *Id.* at 83

[52] *Id.* at 84.

[53] I believe the same problem impacts estimates of avoided CO2 emissions—once again, the report relies here on annual avoided emissions calculated from AVERT—which includes coal plants, whose CO2 emissions are significantly higher than natural gas plants.

[54] Levelization out for many years based on current knowledge, assumes no technological gains in generation and emissions reduction over that period of time, a seriously flawed assumption. Indeed, the authors of the Maine VOS make absolutely no effort to compare the

argue above, should not be considered at all in "value" analysis—market price response (that is, buyer side market power that creates long-term capacity problems) and avoided fuel price uncertainty (in this analysis, the uncertainty that seems to be avoided is lower natural gas costs). The avoided energy cost of 8.1 cents per kWh is tied to what it is already clear are erroneous forecasts of ever increasing natural gas prices, which are brought into play through the magic of "levelized" analysis. And the avoided generation capacity costs (5.6 cents/kWh) do not reflect that this is intermittent and (generally) off peak capacity, and therefore has negligible, if any, impact, on capacity needs—hardly savings the utility can take to the bank. The staggering Maine avoided cost numbers just do not stand up to scrutiny.

Current rate reform initiatives across the U.S.

Unsurprisingly, given the problems with RNM explained above, many utilities are examining how to better structure rates for distributed generation customers. There is a robust debate occurring across the nation regarding the appropriate rate mechanisms for addressing the issues raised by distributed generation technologies, with a growing recognition throughout the United States that traditional RNM is not sustainable as a pricing methodology. For example, in 2015, 46 out of 50 states had ongoing studies, proposals, or enactments relating to "net metering, valuation of distributed solar, fixed or solar charges, third-party or utility-led rooftop solar ownership, or community solar."[55] These states stretched from coast to coast, including Nevada, Ohio, Pennsylvania, Virginia, Connecticut, and Maine.[56]

In the first quarter of 2016, thirty-nine states took some action related to "net metering, rate design, and solar ownership," according to the NC Clean Energy Technology Center's report

---

costs of emissions reductions through rooftop solar with the costs of other means of achieving the same end. Market or price discipline is not even considered in the Maine VOS.

[55] North Carolina Clean Energy Technology Center & Meister Consultants Group, The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report, February 2016: 11.

[56] Ibid, p. 40.

(p.9). The report describes a continuing "trend" of fixed charge increase requests by utilities, with 19 such requests pending at the end of March 2016 (50). Proposed changes are often controversial. Florida has seen dueling proposed ballot initiatives. Hawaii recently ended its RNM program. In Nevada, RNM reform has attracted considerable national attention. Maine has had its own taste of the difficulty of this issue, with the recent legislative and gubernatorial actions on the issue. Other states which are at various stages of review and revision include Kansas, Arizona, Massachusetts, Vermont, California, Wisconsin, Mississippi, Ohio, New Hampshire, Louisiana, and recently Colorado. The old national *status quo* of net metering is being reexamined in a growing number of jurisdictions across the country.

In some jurisdictions, utilities are moving to replace RNM with a three part rate including a demand charge, under which customers pay a monthly charge based on their peak demand for that month. Such a charge can be optimized by setting "peak hours" when it applies. The intellectual appeal of a three part rate is its promise of fully implementing the principle of setting rates in accordance with cost causation for each of the three kinds of costs (fixed, demand, and energy) customers impose on the system. This type of rate reform, however, is often viewed as radical, and may be difficult to implement, though it is worth keeping in mind as a model of what a fully cost-reflective rate might look like.

Overall, many market participants and observers have concluded that, as a class, RNM customers are not covering the costs that a utility incurs in serving them; that, as a result, RNM requires non-solar customers to subsidize rooftop solar customers; and that the RNM subsidy should be reconsidered.

Maine's Proposed Net Energy Billing Reforms

The current proposed reform to Maine's rates, though relatively modest and gradual by the standards of some other reforms being considered around the country, would represent significant progress towards reducing (and, perhaps, over time, eliminating) the cross-subsidy from customers without rooftop solar to customers with rooftop solar, by preserving the ability for rooftop solar customers to get credit for energy they provide to the grid, but by phasing out the current practice of also providing credit for associated transmission and distribution costs, which rooftop solar does nothing to reduce.

The full implications of the billing reform change depend in part of how the Commission decides to apply this new tariff: specifically, they would depend on whether customer rooftop generation that is used by the customer and not exported to the grid is considered to be "nettable energy" or not. Depending on the Commission's final decision, the proposed reform could be a reduction in compensation only for energy exported to the grid, or it could be a reduction in compensation for the total amount of energy produced by rooftop solar, including amounts consumed by the household itself. Either choice the Commission might make in this area has pros and cons. To the extent that the new rule applies only to the energy customers export to the grid, the cross-subsidy from non-solar customers is not fully eliminated, in that customers who consume their own energy get bill savings that not only savings on energy costs for non-solar customers, but savings on grid and transmission services, which are inappropriate since demand and fixed costs are always being incurred on behalf of solar customers to enable them to import and export energy and to provide full back up to their intermittent on premises generation. ,If eliminating this remaining cross-subsidy is a priority, one option is to adopt a "buy all, sell all" approach to Net Energy Billing—for billing purposes, this would mean that the customer "sells" all his or her rooftop solar production to the grid at the new rate, and then supplies all of his or her consumption at current electricity rates.[57]

It should be recognized, however, that a "buy all, sell all" approach has certain disadvantages that the Commission may wish to consider, including potential negative tax implications for customers with rooftop solar generation[58]. Furthermore, in the context of Maine's energy tariffs, which in many cases are flat over the course of the day ("peak" rates are offered by some utilities, but they are optional), there may be efficiency incentives for rooftop solar customers inherent in a system which rewards home consumption more than excess energy provided to the grid—this gives customers an incentive to manage their demand and production in ways which maximize the overlap between their own consumption and solar production, potentially helping to reduce their peak demand.[59]

It is important to recognize, however, that either approach, by gradually eliminating credit for transmission and distribution services whose costs are not offset by solar power production, would represent a significant improvement over the current over compensation of

---

[5757] This may, in fact, be what is intended in the new rule.

[58] See Hines, Kayci G., "Solar Shift: An Analysis of the Federal Income Tax Issues Associated with the Residential Value of Solar Tariff." *Arizona Journal of Environmental Law & Policy* Vol. 5: 388, 2015.

[59] Although this is not the issue currently before the Commission, in the future it might well be worth considering moving to more extensive use of rates that in some way reflect the differing impacts of energy consumption at different times of day, sending customers a price signal that better reflects the actual costs of their energy use during peak hours—and the actual value of energy produced at peak hours as well. This kind of pricing structure may become increasingly valuable as various potentially peak shifting resources and new sources of electricity demand (such as rooftop solar, battery storage, demand management, and electric vehicles) become more and more common.

rooftop solar production, and would be an important step in correctly aligning customer incentives and in treating all customers fairly.

Conclusion

The inequities and inefficiencies of existing retail net metering rates across the country are increasingly being recognized as both unjustifiable and unsustainable in a world in which rooftop solar power is no longer an infant industry, but rather a growing a robust part of the energy sector. The long-term success of distributed solar as an energy resource must depend on its becoming truly cost competitive with other resources, and rate reforms to more realistically compensate distributed solar are an important part of making this transition. The Commission's proposal to revise the current Net Energy Billing to bring it closer to what its name suggests ("net *energy* billing," not "net energy, transmission, and distribution billing) is an important step in the right direction.

Appendix A: Biographical Information for Ashley Brown

Ashley Brown is an attorney. He served 10 years as a Commissioner of the Public Utilities Commission of Ohio (1983-1993), where he was appointed and re-appointed by Governor Richard Celeste. He also served as a member of the National Association of Regulatory Utility Commissioners (NARUC) Executive Committee and served three years as Chair of the NARUC Committee on Electricity. He was a member of the Advisory Board of the Electric Power Research Institute. He was also appointed by the U.S. Environmental Protection Agency as a member of the Advisory Committee on Implementation of the Clean Air Act Amendments of 1990. He is also a past member of the Boards of Directors of the National Regulatory Research Institute and the Center for Clean Air Policy. He has served on the Boards of Oglethorpe Power Corporation, Entegra Power Group, and e-Curve, and as Chair of the Municipal Light Advisory Board in Belmont, MA. He serves on the Editorial Advisory Board of the *Electricity Journal.*

Ashley Brown has been at Harvard continuously since 1993. He has also taught in training programs for regulators at Michigan State University, University of Florida, and New Mexico State University (the three NARUC sanctioned training programs for regulators), as well as at Harvard, the European Union's Florence School of Regulation, Association of Brazilian Regulators, and a number of other universities throughout the world. He has advised the World Bank, Asian Development Bank, and the Inter-American Development Bank on energy regulation, and has advised governments and regulators in more than 25 countries around the world, including Brazil, Argentina, Chile, South Africa, Costa Rica, Zambia, Ghana, Tanzania, Namibia, Equatorial Guinea, Liberia, Mozambique, Hungary, Ukraine, Russia, India, Bangladesh, Saudi Arabia, Indonesia, and The Philippines. He has written numerous journal articles and chapters in books on electricity markets and regulation, and he is the co-author of the World Bank's *Handbook for Evaluating Infrastructure Regulation.*

He holds a B.S. from Bowling Green State University, an M.A. from the University of Cincinnati, and a J.D. from the University of Dayton. He has also completed all work, except for the dissertation, on a Ph.D. from New York University.

Appendix B: Documents Relevant to Solar Installation Prices (Provided at the request of Commissioner McLean)

At the request of Commissioner McLean, I am providing links to the following documents, relevant to my discussion, at the October 17, 2016 public hearing, of why residential solar installation prices seem to be above cost and international benchmarks:

Barbose, G. L., N. R. Darghouth, D. Millstein, S. Cates, N. DeSanti, and R. Widiss (2016), "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photo- voltaic Systems in the United States," Tech. rep., Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA (United States).
https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report_0.pdf

Feldman, David, Galen Barose, Robert Margolis, Ted James, Samantha Weaver, Naim Darghouth, Ran Fu, Carolyn Davidson, Sam Booth, and Ryan Wiser. "Photovoltaic System Pricing Trends." (September 22, 2014): 30. Available online at:
http://www.nrel.gov/docs/fy14osti/62558.pdf

Fu, Ran, Donald Chung, Travis Lowder, David Feldman, Kristen Ardani, Robert Margolis. NREL. September 2016. "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016."
http://www.nrel.gov/docs/fy16osti/66532.pdf

The Future of Solar Energy: An Interdisciplinary MIT Study. MIT (2015).
https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

Gillingham, Kenneth, Hao Deng, Ryan Wiser, Naim Darghouth, Gregory Nemet, Galen Barbose, Varun Rai, and C.G. Dong. *Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy.* (December 2014): 20-21. Available online at:
http://www.seia.org/sites/default/files/LBNL_PV_Pricing_Final_Dec%202014.pdf

Lazard's Levelized Cost of Energy Analysis-Version 9.0. November 2015. Full report available online at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf